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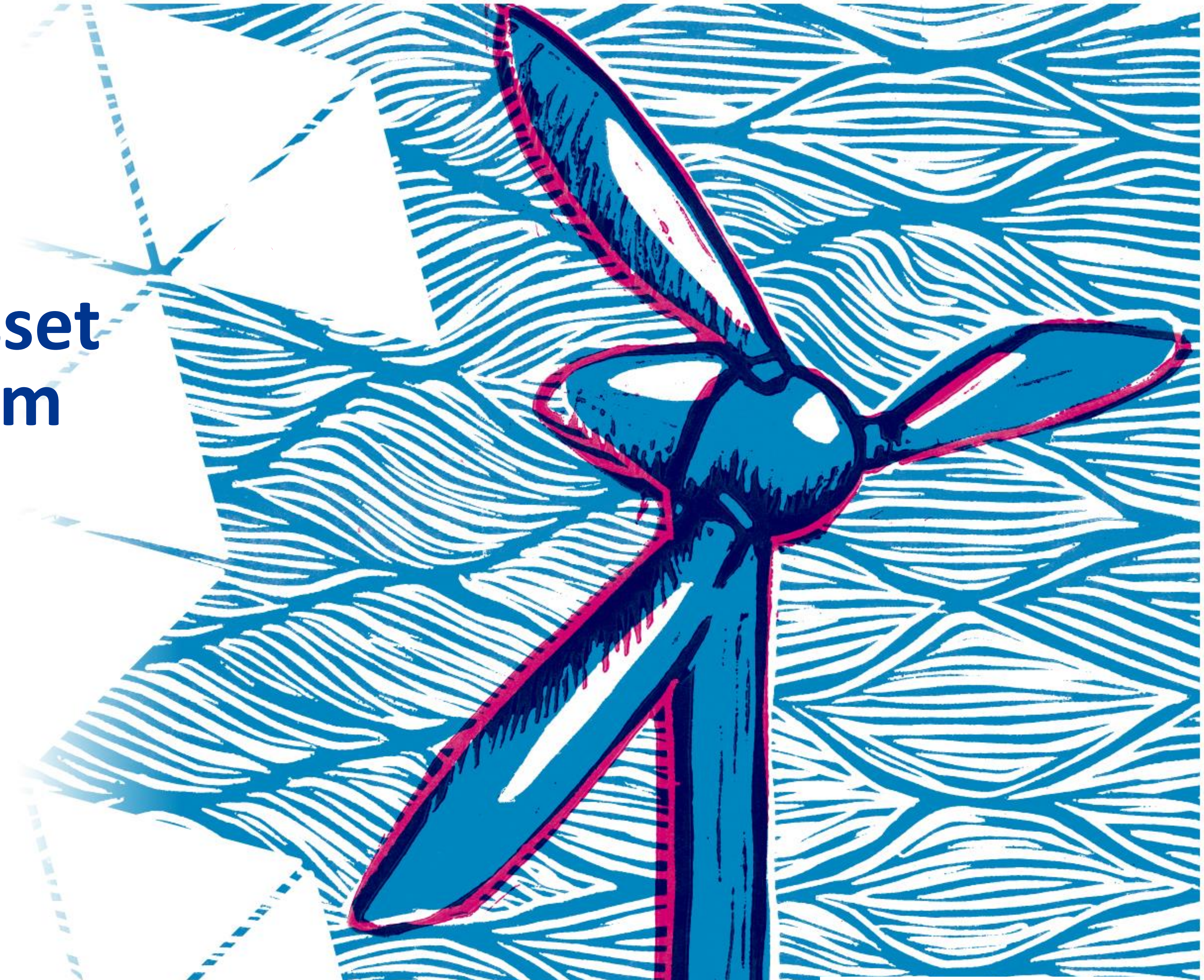
Offshore Wind asset value impacts from TDTR

Report

March 2025

Commissioned by: Energie-Nederland

ENERGIE NEDERLAND



"51% Load Factor" – Linocut – 2024
Ezekiel Lee, Baringa Consultant in Power and Low Carbon Solutions

Baringa has been commissioned by Energie-Nederland to provide a report outlining the potential impacts of the proposed time-dependent transmission right

The upcoming new regulations on NL grid connections for offshore wind have sparked discussion on the potential impacts of grid management measures. We have undertaken analysis to assess the impact of proposed Time-Dependent Transmission Rights (TDTR) for offshore wind in the Netherlands

What is the proposed new rule?

- The new connection type, TDTR, would reserve the right for the TSO, TenneT, to curtail a portion of the wind farm output for 15% of the hours in a year. This would be in hours where grid congestion needs to be mitigated

The offshore wind sector has shown signs of fragility in recent years, but ambitions remain high across Europe

- Offshore wind plays a critical role in decarbonisation in the Netherlands, with a commitment for 75% of electricity demand to be sourced from North Sea Wind Farms by 2032. For this, several tenders are planned in the coming years to reach a target of 21 GW in operation
- Recent developments such as tight supply chains and increasing cost of capital, in combination with slower than projected electricity demand growth, have added pressure to the business case for offshore wind sector

Congestion and grid tariffs are a major issue in the Netherlands. The TSO and government are seeking to address connection queues and high costs

- Network congestion in the Netherlands remains an issue. The Network Code is being updated to support non-firm grid connections

Baringa is a trusted advisor to renewable developers, system operators and policy makers across Europe and a leading provider of energy policy advice to governments and investors

- Baringa is an established international consultancy with a strong reputation in the energy sector. We have supported developers in their strategy for participating in competitive tenders or securing offtake agreements, providing market-leading modelling on key project revenues and costs, and undertaken energy policy reform assessments across different markets
- We have been involved in auctions in the UK, Ireland, France, the US, and the Netherlands in the last 2 years. We have advised over 20GW of participating capacity in some of the latest allocation rounds across GB and EU. We have also advised European governments on the design of renewable tenders
- To deliver this report we have undertaken analysis using our in-house market modelling capability which is widely used by developers, investors and banks as inputs in their investment decisions, transactions, and strategy
- For this study, we have looked at the impact of the TDTR on one wind farm that would have hedged their revenues through a corporate PPA for 15 years and compared a firm grid connection to the same asset with TDTR

Vlad Parail
Partner, London

Cliff Bleeker
Senior Consultant, Rotterdam

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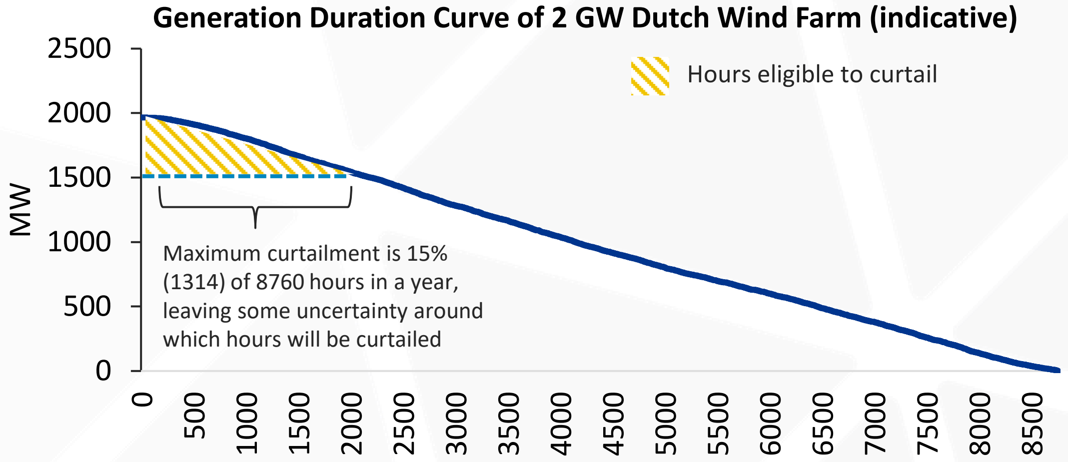
Wind developers could be subject to Time Duration Dependent Transmission Rights (TDTR) as part of the Dutch offshore tender criteria

The Dutch regulator and grid operators have been working on reforms to mitigate congestion, introducing new connection types

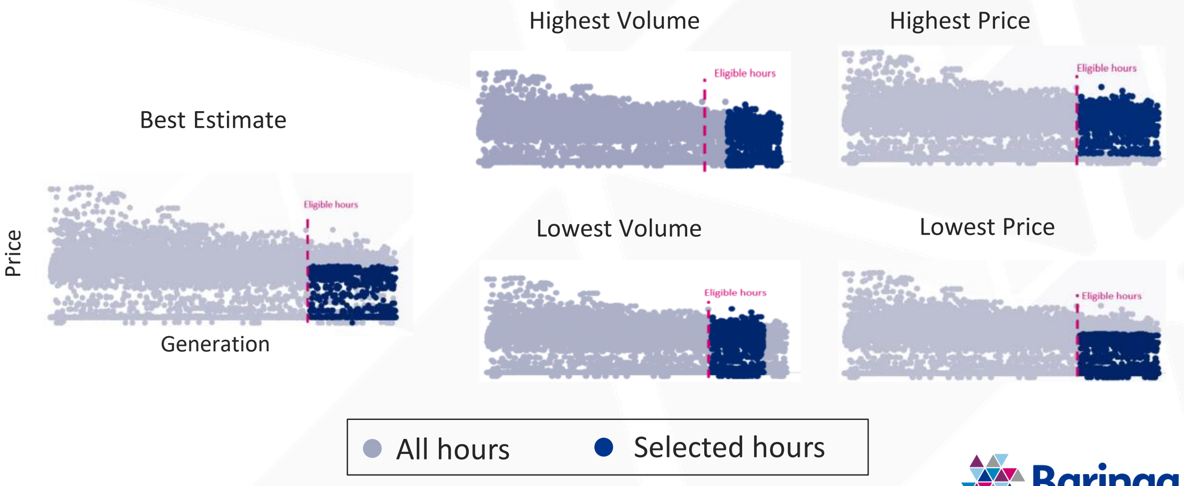
- Non-firm connections allow grid operators to limit the connection capacity when there is expected congestion on the grid

TDTR is planned to be part of offshore wind tender criteria in future

- Due to projected congestion onshore, network operators propose a new connection type, allowing curtailment of wind assets in 15% of operating hours
- TDTR is already an option for onshore generators, but the Network Code change enables these connection and transmission contract types to be enforced for offshore wind via tender criteria
- TenneT suggests to include the TDTR included as part of the tender criteria for the upcoming offshore wind tenders
- When bidding for the tender, the wind developer will have two choices to subscribe in the tender:
  1. Realise additional demand; where the developer demonstrates additionality of new demand linked to with project generation
  2. Take on the TDTR for the upper part of your connection capacity
- TDTR is expected to apply to a portion of production capacity (assumed to be 25% in this report) for a maximum duration of 10 years



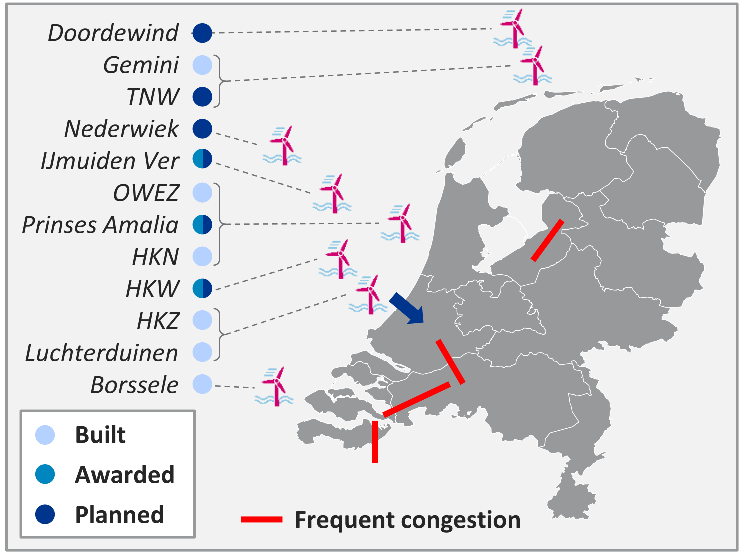
A wind developer does not know which hours will be curtailed, having limited information compared to the TSO. A range of possibilities could happen, which they need to account for in the business case:

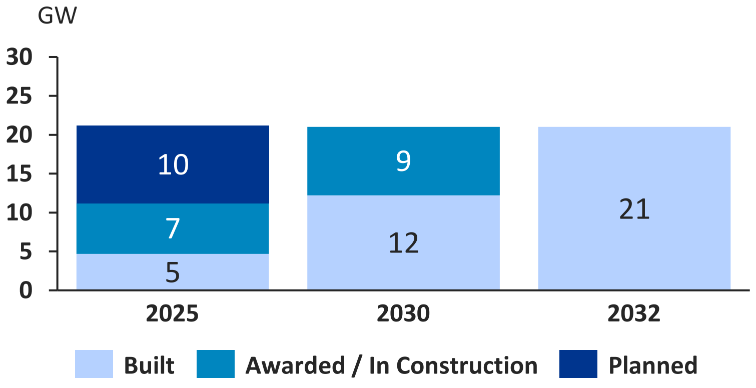


Note: More details on the exact rules of TDTR and further definitions and results of the sensitivities are in the appendix

In addition to a cost transfer from TSO to generators, the potential for higher cost of capital costs and internalized risk premia increase the overall costs of wind buildout

The Dutch government plans a rapid growth in offshore wind while in parallel needing to solve increasing costs of congestion





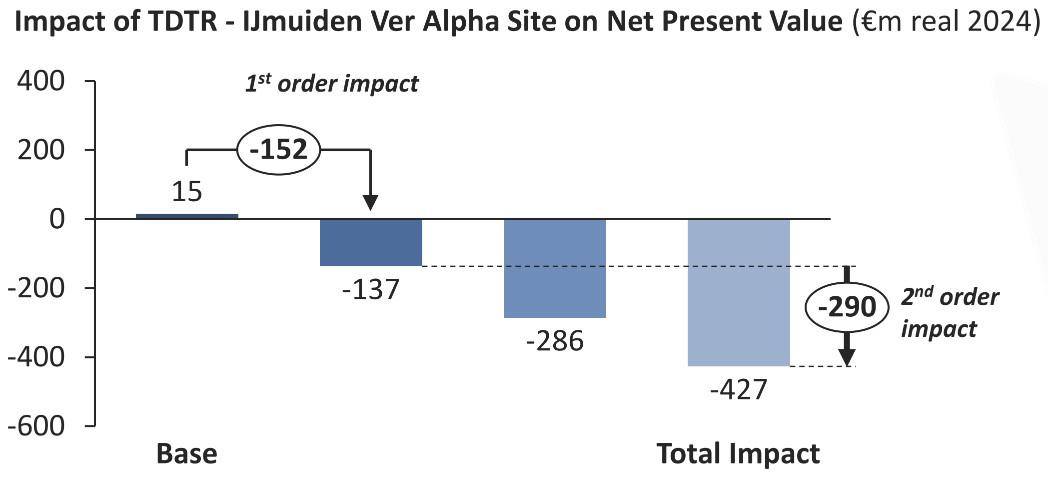
Although TDTRs reduce costs for the TSO, they may translate into higher overall costs which are borne by consumers

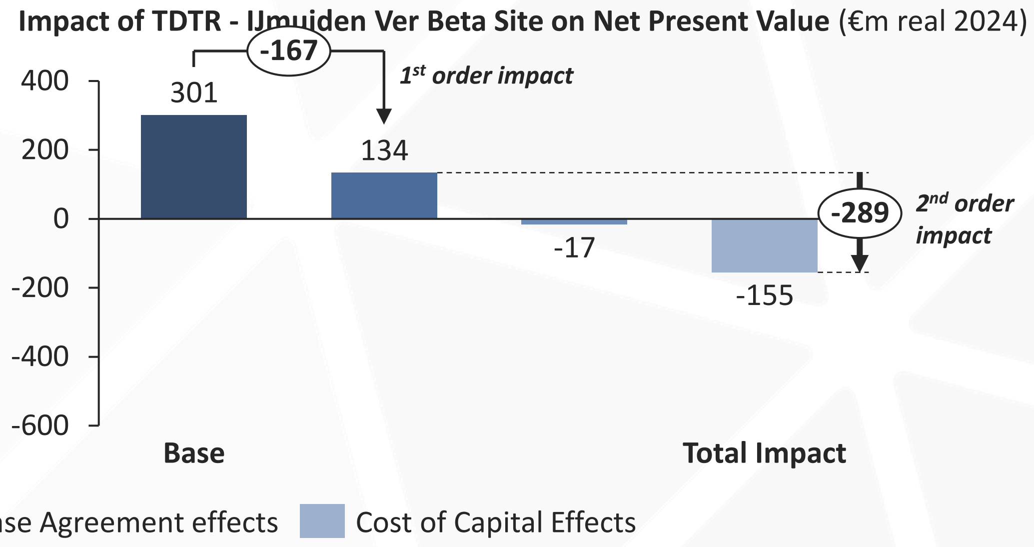
Time-duration dependent transmission rights may disincentivise wind developers from investing - curtailment being applied to offshore wind results in a significant NPV loss for the projects. This exacerbates challenges around viability of offshore wind projects. Recent examples from Europe have already shown a decreased appetite for bidding in tender processes, demonstrating supply chain challenges

The measure may lead to higher costs to develop offshore wind due to knock-on effects for the PPA and cost of capital - the potential NPV loss is not limited to the effect of the volume loss from curtailment. Due to uncertainty and increased risk, an offshore wind project may face lower willingness to pay from an offtaker and a reduced capacity to take on debt, increasing the project cost of capital. This will ultimately increase the levelized cost of energy (LCOE) of the project and electricity costs in the Netherlands beyond the cost and risk transfer from grid operator to developer

This change poses risks to the Dutch offshore wind model - Our analysis suggests a 2-3 €/MWh higher PPA price would be needed to offset the cost impact for a representative offshore wind project. Introducing TDTR may require other measures such as compensation, or facilitating greater demand and willingness to pay for project generation, and risks delays in the offshore wind rollout

Greater curtailment risks may result in reduced investment appetite from offshore wind developers - estimated NPV losses range from €150m to over €440m





1st order impact: *the 1st order effect is the transfer of risk and costs of redispatch from the grid operators to the wind developer, which transfers costs but does not increase their total*

2nd order impact: *second order effects are knock-on effects, additional to the revenue loss from curtailment. These costs would contribute to higher costs to develop offshore wind in the Netherlands*

Conclusion: Our analysis of the potential impacts time duration-dependent transmission rights suggests a **significant negative impact on the Net Present Value (NPV)** of the projects. Focusing solely on the generation curtailed and not considering other factors, we project an **NPV loss exceeding €150 million**. Sensitivity analyses indicate that the NPV loss could range between €88 million and €181 million.

Additionally, there are **second-order effects** that would further reduce the project's value and ultimately **increase costs to develop offshore wind in the Netherlands**. Increased uncertainty and risks that developer, offtaker and lender now carry may translate into higher project costs, which may not be incurred when the congestion risk is managed by the TSO.

Approach

We modelled IJVer Alpha & Beta to see the relative impact on the project investment case if they would be subject to ATR-85

Methodology

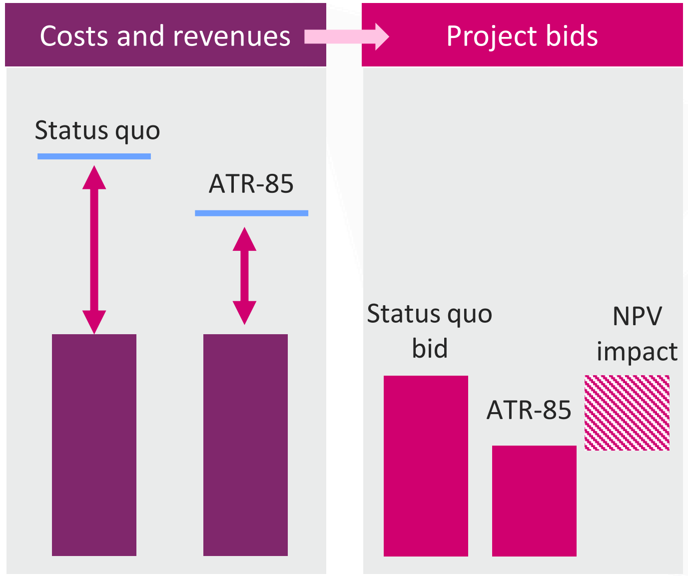
For the sites now won by the Noordzeker and Zeevonk II projects, we have built up a detailed view of the key costs, revenues and generation volumes based on our market and technical expertise. Key site characteristics considered include:

- **Physical and technical project characteristics:** we have incorporated an assessment of projects costs and projected power generation
- **Financial and delivery considerations:** we have accounted for project financing assumptions and expected project delivery timelines to inform our view
- **Offtake price:** we have calibrated a realistic PPA offtake price – based on bottom-up analysis of the site (minimum breakeven level), our capture price projections for the Dutch market and our understanding of acceptable levels in the Dutch PPA market

The **change in tender bid and project NPV was calculated on the basis of projected future cashflows at the targeted developer rate of return at the site in question.**

We assessed **two cases: (i) one based on the status quo, leveraging our existing methodology and (ii) one with the levels of curtailment based on the ATR-85** rules and our view of the hours subject to curtailment.

Illustration – valuation impact



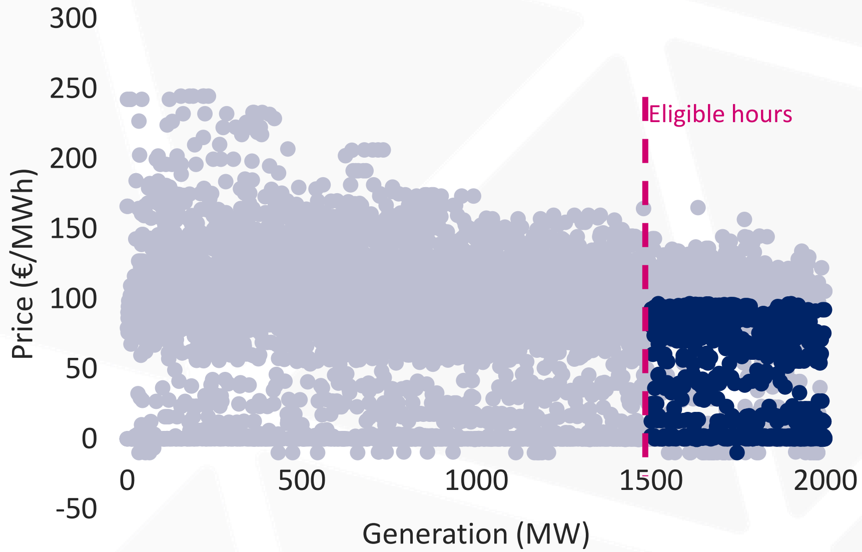
This illustration shows that a direct revenue reduction leads to a corresponding impact on the valuation of the seabed.

Legend:
NPV of revenues
Project costs
Difference between revenues and costs
Bid

Market and network parameters:

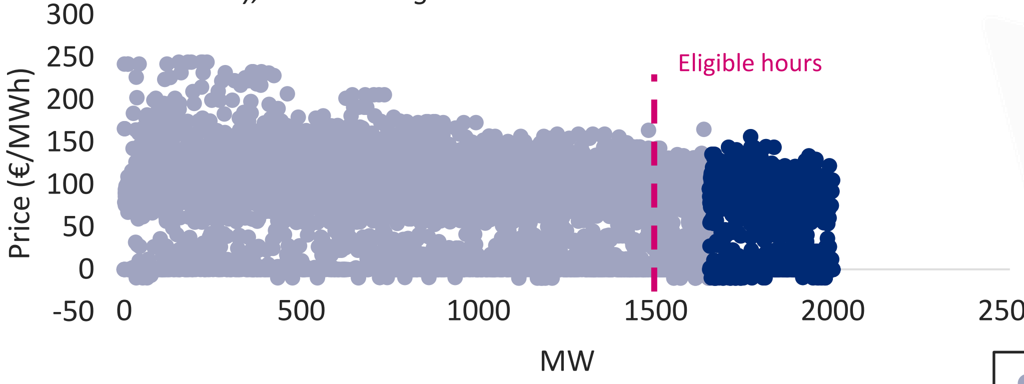
We have proxied the hours to be curtailed by ATR-85 based on a set of conditions informed by the TenneT projections on the congestion at the Geertruidenberg node/line and Rilland line

See more details on this approach in the appendix.

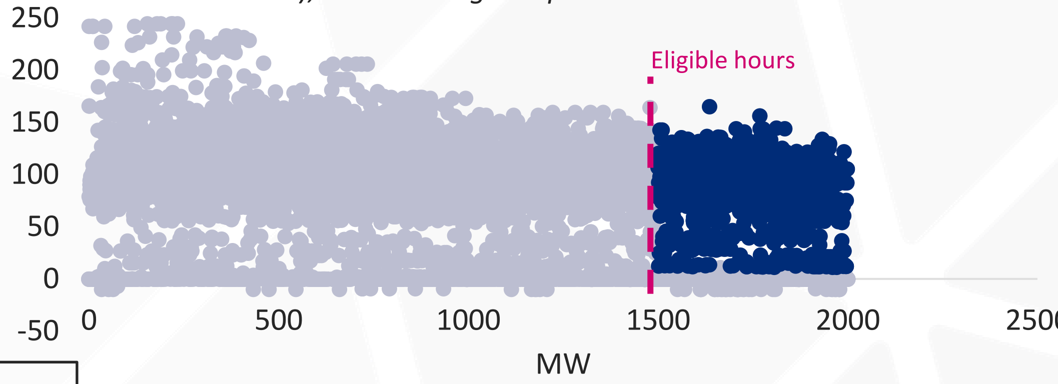


The TDTR could lead to a range of outcomes with varying levels of curtailment, we looked at four sensitivities of the possible curtailment levels

***1) Highest Volumes**: of the hours that are eligible to curtail (wind >1500 MW), the 1314 highest volume hours are curtailed.*

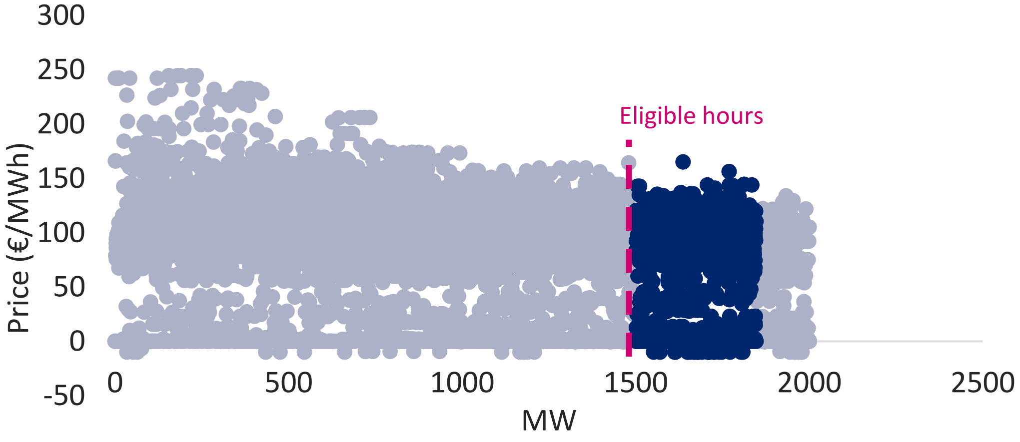


***3) Highest Prices:** of the hours that are eligible to curtail (>1500 MW), the 1314 highest price hours are curtailed.*

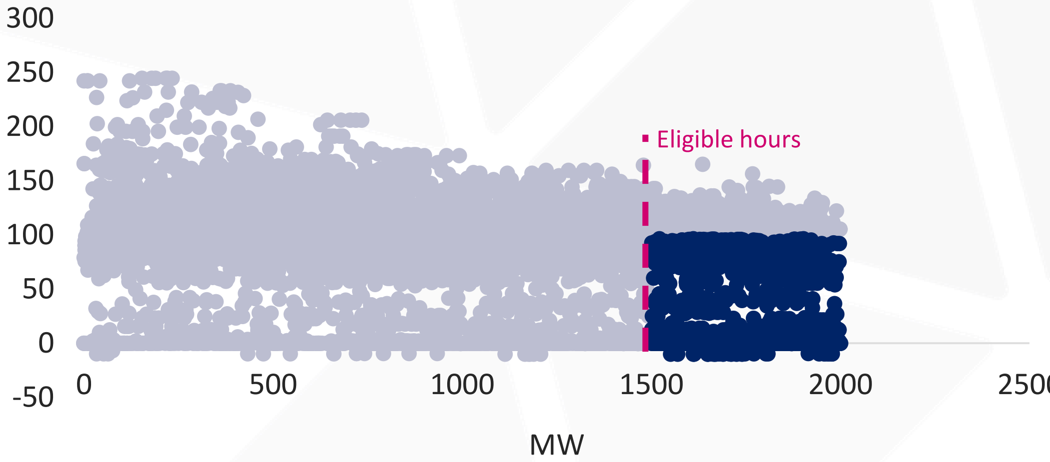


All hours
Selected hours

***2) Lowest Volumes:** of the hours that are eligible to curtail (wind >1500 MW), the 1314 Lowest volume hours are curtailed.*



***3) Lowest Prices:** of the hours that are eligible to curtail (>1500 MW), the 1314 Lowest price hours are curtailed.*



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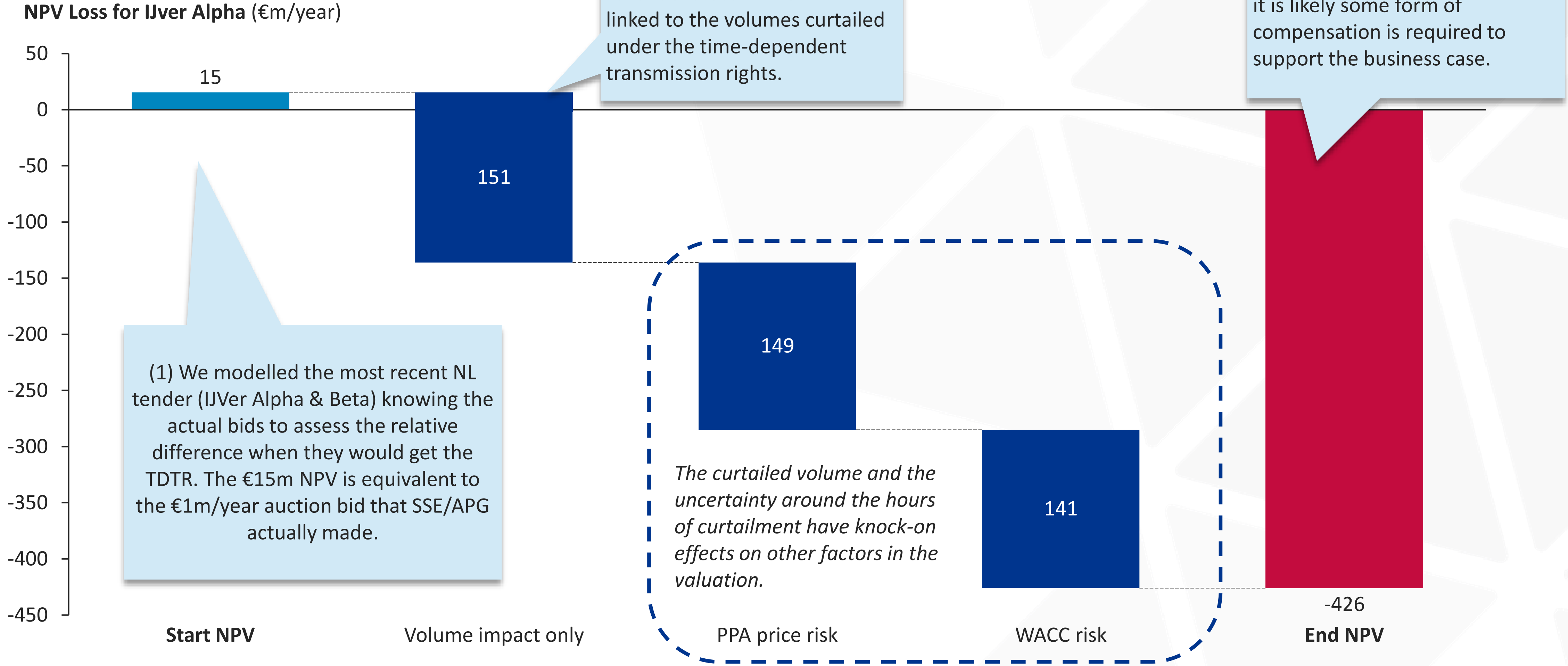
Results

The impact of the curtailment on valuation is seen in three major factors, which have a causal sequence

We conducted a site-specific analysis to understand the valuation impact associated with the new connection type



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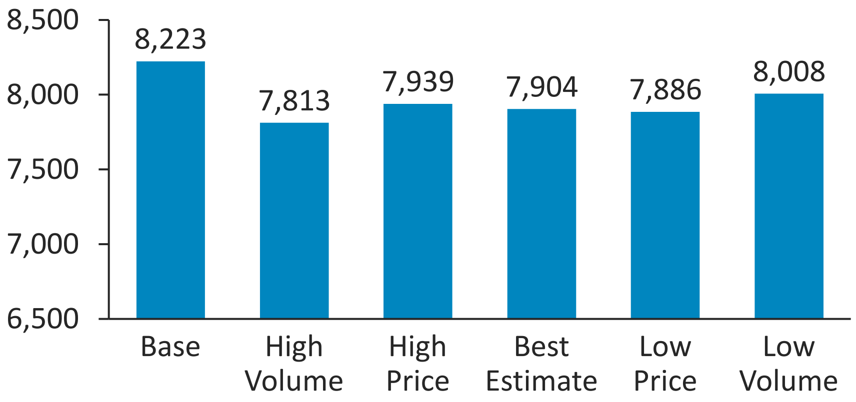
Loss of volume may decrease project NPV by up to 197€m due to the lower revenue following the curtailment loss

Key revenue impact is the potential loss of PPA revenues

- Most large offshore wind projects will hedge their income through a fixed-term, fixed price pay-as-produced PPA
  - We estimate a c.69 €/MWh PPA price was agreed for the IJmuiden Alpha site, for the years 2030-44
- In a conservative analysis of the valuation, the wind farm is only affected by the loss of generation volume and PPA revenue loss linked to reduced generation
- There may also be subsequent effects on the PPA willingness to pay and the project cost of capital
- We consider the volume loss caused in 2030-39 under the PPA at the PPA price to estimate the NPV impact

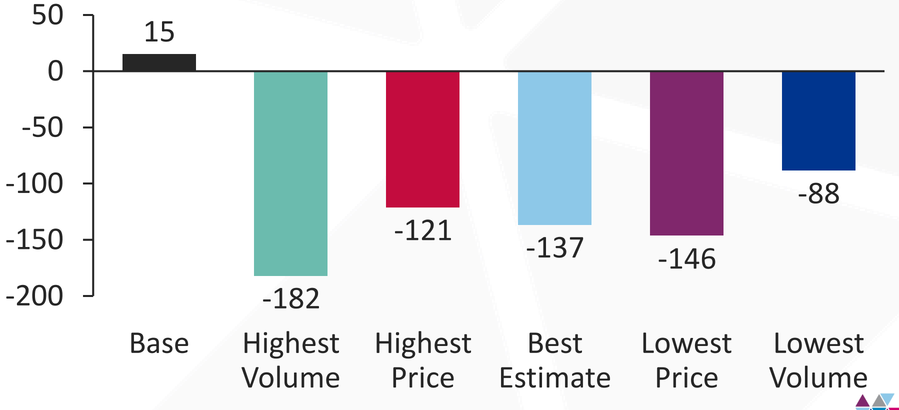
Average generation Alpha site after curtailment under different scenarios (GWh)



The NPV loss remains significant at lower levels of curtailment

- A developer has to estimate the level of volume loss that may be caused through TSO curtailment actions. Therefore, a range of scenarios were created to align with the connection conditions, see more info in the appendix
  - **Best estimate**: using Baringa modelling of hourly of generation/demand/flows and prices, we replicate the congestion by looking at high wind/low demand + export to Germany and Belgium
  - **Highest/Lowest Volumes:** of the hours that are eligible to curtail (wind generation >75% of capacity), the 1314 highest/lowest volume hours are curtailed.
  - **Highest/Lowest Price:** of the hours that are eligible to curtail (>75% wind generation), the 1314 highest/lowest price hours are curtailed

NPV alpha site (€m)



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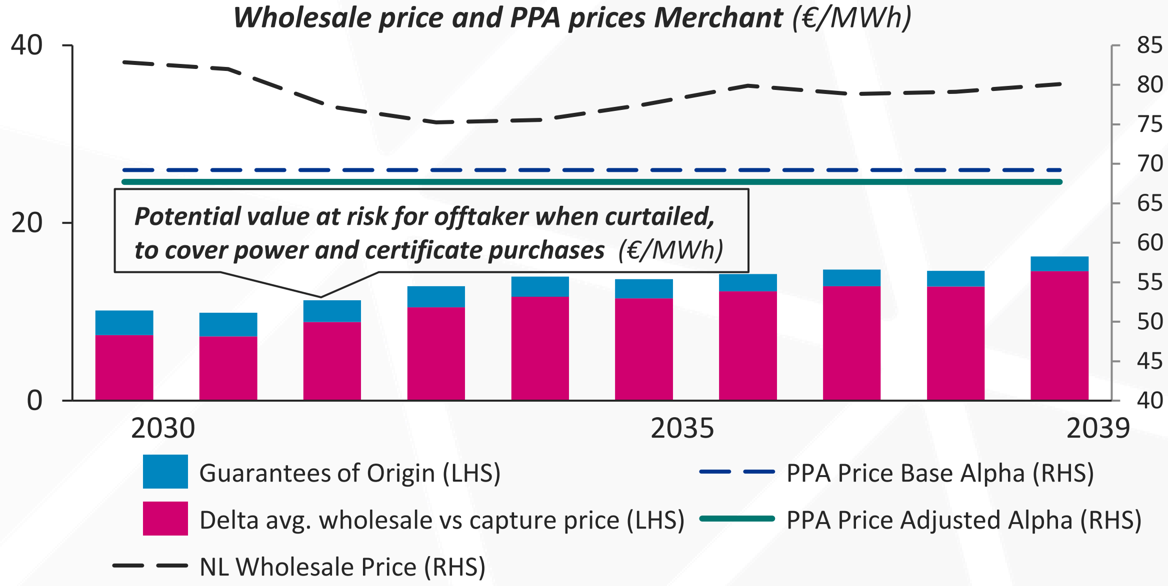
A PPA offtaker may reduce its willingness to pay due to the new curtailment rules, making it harder to achieve a PPA price that can underpin investment

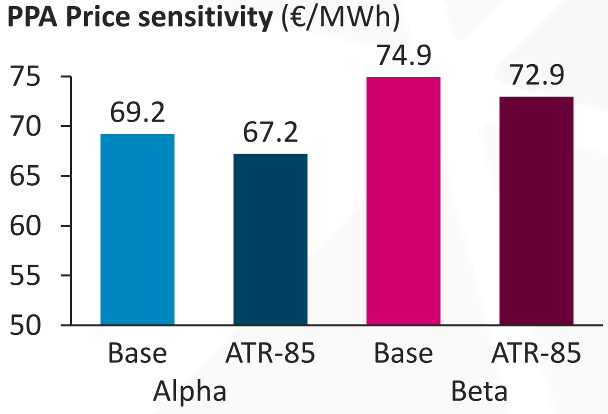
Additional to the volume loss itself, there is a risk that a lower PPA capture price is achieved due to the offtaker adding a risk premium

- The common route-to-market for offshore wind farms is currently through PPA agreements
- If the wind project negotiates a PPA that creates new power demand in NL (equivalent to generation), they would be exempt from the TDTR agreement. It is unclear what requirements the demand would have to meet to allow conversion of the TDTR to firm connection capacity
- For this case we assume a utility offtaker would take on the wind generation in its portfolio via a pay-as-produced PPA: This means the PPA offtaker is exposed to the curtailment risk and uncertainty of the wind asset

Downside risk: the PPA price achieved by the generator may be less competitive

- An offtaker would manage the price and shape risk of curtailment, in combination with existing strategies to shape power purchases around projected generation due to weather factors. The offtaker would have no assurance as to the timing of curtailment due to grid constraints
- To manage this risk, the offtaker may add a risk premium which would reduce their willingness to pay for the power. With limited information on the curtailment, the offtaker may assume the most readily available view of the value of power, which is the average projected baseload price:
  - The risk can be represented by assuming that the average value, or opportunity cost, of the power and GoOs curtailed is the baseload wholesale price and projected average GoO value respectively
  - In practice, hours of curtailment may be at periods of lower than average prices (due to high wind or import availability). This could be a benefit for the offtaker; if the TSO provided greater clarity on which hours or system conditions would lead to curtailment this risk can be reduced





This second order effect could further decrease the NPV by €149m in addition to the impact of volume loss

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Lower projected revenues may reduce the maximum debt finance that can be raised, which in turn may increase the project WACC

We assume a wind project aims to takes on maximum amount of Debt as it costs less than Equity, ensuring the lowest WACC

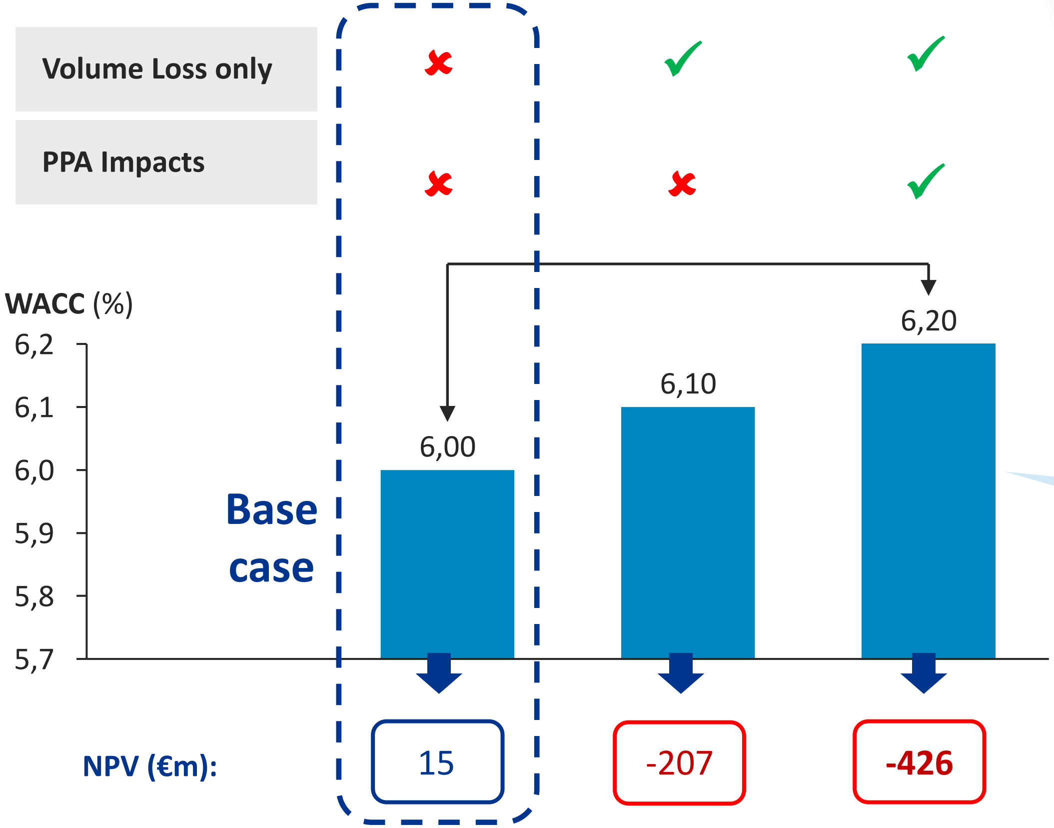
Maximum debt amount is determined by the Debt Service Coverage Ratio (DSCR), which is the cash flow you need to fulfil your debt payments

We assume an 80/20 debt/equity ratio was reached in the Base case

The revenue loss from the TDTR can be converted to a % loss of annual income for the project, equivalent to the decrease of debt payments that can be made

The lower amount of debt that can be taken on translates reduces the ratio of debt to equity

Needing to put more Equity in the project requires a higher rate of return for that part of the investment, increasing the Weighted Average Cost of Capital



WACC Impact from ATR-85

Without revenue support or top-up, the cash flow of the project is projected to be lower due to ATR-85, reducing the maximum debt payments that can be made each year

We estimate that this loss is equivalent to the level of extra equity required by the project to offset reduced debt availability

The higher expected rate of return required for equity investment causes the cost of capital to increase

The project NPV is very sensitive to increases in Cost of Capital.

The increase in this cost can also be seen as pure additional costs to the whole system as it is a pure financial cost but no value is added to either the developer or the consumer

Note: The debt payments are assumed to be made in the first 15 years of the project where the revenues are hedged against the PPA. This would ensure the lowest WACC possible that the developer can achieve

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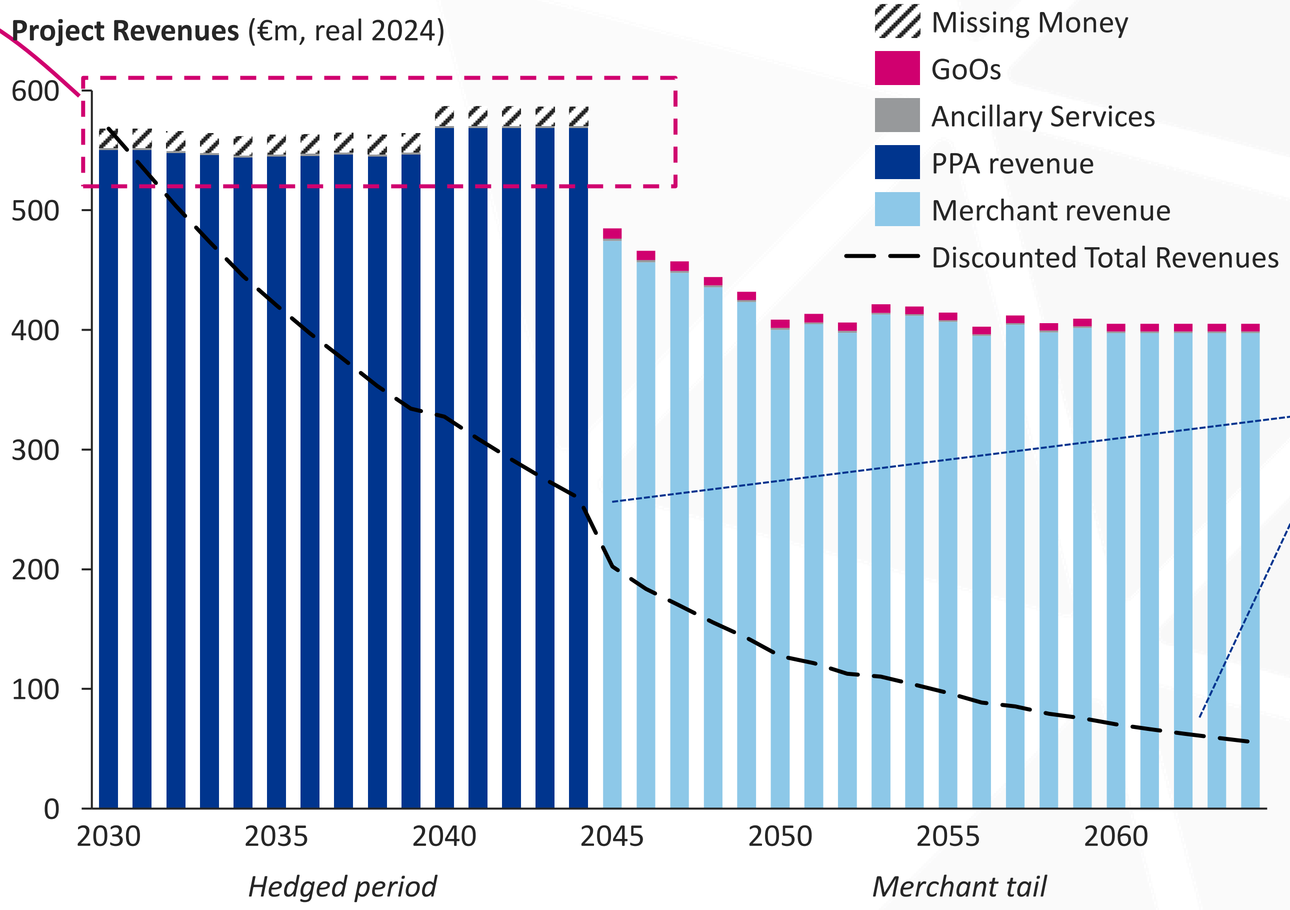
Our results imply that a 2 GW wind project could need an annual revenue increase of c.€16m to make the project viable

Projects commonly need a guaranteed price in the first 15 years to make projects bankable, but we estimate 2-3 €/MWh to be missing in the market

We looked at the conditions which would be required to ensure project viability. We estimate that **a 2-3 €/MWh increase** in contracted revenues would be required. Available market benchmarks suggest that there is limited appetite for such increase in the PPA market

This uplift would have to come from (1) an **increase in willingness to pay from the PPA offtaker** or (2) a **degree of certainty and support backed by the NL government**



After discounting, **54% of discounted revenues are earned in the first 10 years of the project.** Typically, due to the discount rate applied, the revenues at the first 15 years of the project are far more important than the merchant tail

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Appendix

We defined several scenarios for likely curtailment to estimate revenue impacts

These conditions form our 'Best Estimate' scenario, where on average c.1300 hours between 2030-2039 are curtailed

Scenario Factors *(right)* → **Scenario Names (*down*)**	**High Wind generation**	**Solar generation**	**Demand levels**	**Import Flows**	**Export Flows**	**Rationale for curtailment**	**Hours Relevant (2030)**
1) High offshore wind	✓					Only hours where generation is above the firm connection threshold (>75%) are eligible for curtailment	**1893**
A) Low Demand	✓		↓			In low demand hours, power needs to flow away from the west coast to accommodate offshore wind inflows. Demand in the western provinces by high demand centres is not sufficient to consume all wind generation	**330**
B) Transit & high import flows	✓			✓	✓	High import flows from Scandinavia (DK, NO) lead to transit flows to BE, DE for 50% of the time when there is also high wind. This is likely to lead to congestion on the same lines projected to have congestion due to high wind generation. Also demand in Northern NL is likely to be low in these periods, so power may be expected to flow southward possibly further causing congestion.	**441**
C) High Exports	✓				✓	Not fully overlapping with low demand scenario, there are hours where we see NL exporting to both BE and DE during high wind. This will likely lead to congestion in the Geertruidenberg area	**348**
D) High wind, low solar, high demand	✓	↓	↑			With low solar and high demand but high wind, a major portion of supply will come from offshore wind, likely needing to flow east and southwards	**409**

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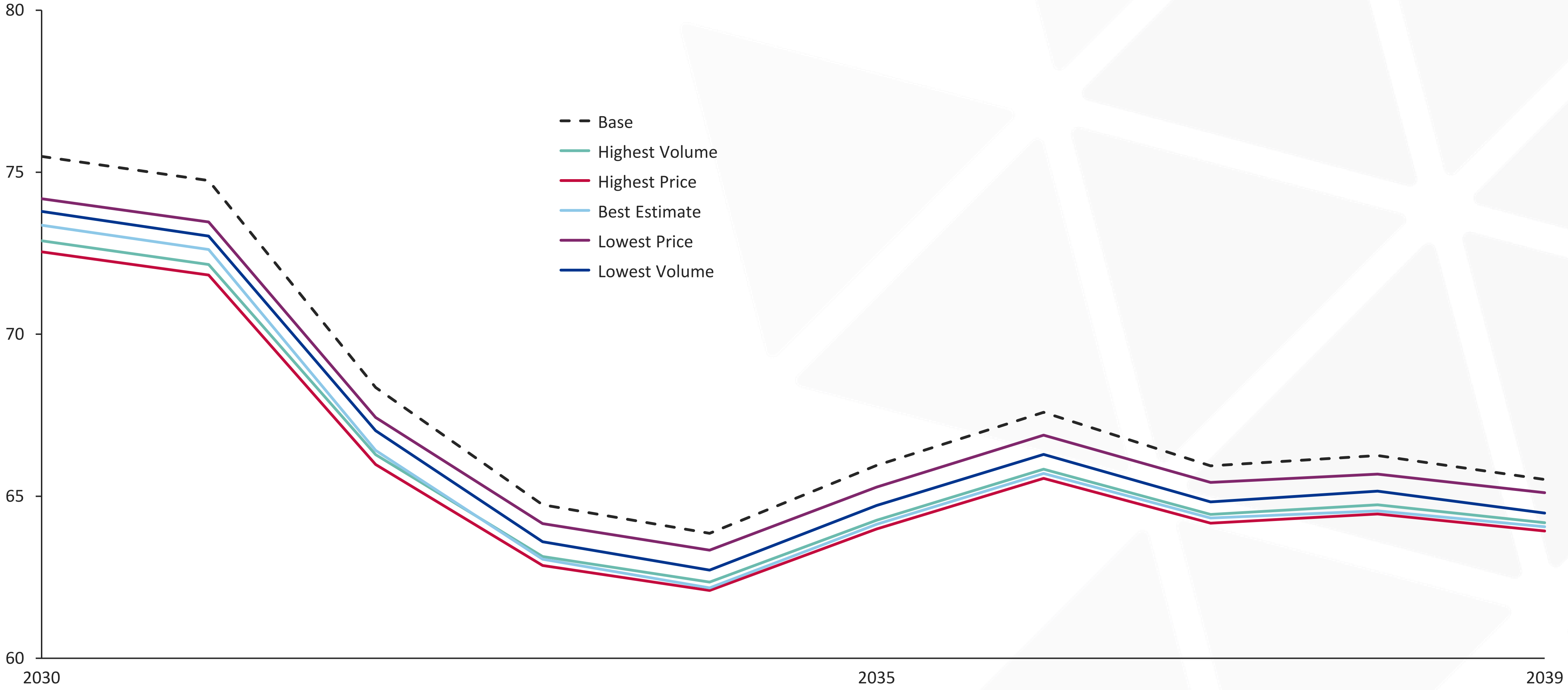
Sensitivities for the possibilities around curtailed hours effect on capture prices if asset would be merchant

Merchant capture price for Offshore Wind in NL (EUR/MWh, real 2024)



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Site data used as starting assumptions for the base case to model IJmuiden Ver Alpha & Beta (Noordzeker & Zeevonk II)

Summary – Base case

Project assumptions

- Both projects will commission End 2029
- Construction time of 3 years
- 35-year project lifetime
- Decommissioning at end of life
- Lease payments for 40 years

Site	Central P50 Generation (GWh)
Alpha	8,223.30
Beta	8,348.30

Project data

- Central values for project costs for CAPEX and O&M costs.
- Net Alpha and Beta site P50 generation data are our internal view.
- **N.B.** We assume that the Net AEP values provided match the definition set out in the tender documents: Net electricity production, availability, wake effects, electricity losses and curtailment losses are taken into account.

		Alpha site / Noordzeker	Beta site / Zeevonk
Developer		SSE/ APG	Vattenfall /CIP
CAPEX	€'k / MW	2895.17	2855.75
Fixed O&M	€'k / MW p.a.	34.40	34.71
PPA Price	€ / MWh	69.2	74.9
PPA Tenor	Years	15	15
WACC	%	6.00%	6.50%
AEP	GWh	8223.30	8348.30

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